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ORIGINAL

April 2, 2001

To: Arizona Corporation Commission Chair  
William A. Mundell

Arizona Corporation Commissioner  
Jim Irvin

Arizona Corporation Commissioner  
Marc Spitzer

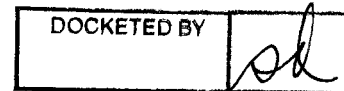
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From: Steve Brittle, Don't Waste Arizona, Inc.



Re: Additions to My Previous Testimony

It has come to my attention that there was an attempt to rebut my testimony. Someone claimed that ammonium salts would not be formed by using the SCR technology, that the ammonia to be used by SRP is not a hazardous substance, that an economic analysis was part of the decision-making process in choosing air pollution control technologies, and that SCONOX doesn't work on large generating facilities.

I offer the following exhibits (25 pages) with accompanying discussion to support my statements:

**Exhibit 1** is four (4) selected pages from correspondence in the Maricopa County Environmental Services public files regarding the air pollution permit for Duke Energy's Arlington Valley Energy Project (AVEP). On the first page of the exhibit, you will notice the graph that talks specifically about the costs of increasing the control of NOx. The next pages are marked to draw your attention to the excess ammonia injected into the process and the extra particulate matter that will be produced, with the last page ending with the discussion and quantification of the extra particulate matter added by the SCR system (12 lbs/hr) and the baseline particulate emissions (20 lbs/hr) from each turbine.

If a power plant is projected to emit 267 tons/year of PM10, it is easy to project from these AVEP figures that over 100 tons/year would be ammonium salts. The ammonium salts emissions most assuredly wouldn't be zero. For anyone to assert that in Arizona's climate, ammonium salts won't form, is irresponsible.

**Exhibit 2** is five (5) pages from the AVEP permit application. Besides the consistent reference you see to Economic Evaluation, as the costs and merits of control technologies are compared, you will see the discussion and admission of the ammonium salts being formed. Indeed, on the last page, Under "Environmental Impacts," we find, "Ammonia salts (pm10/PM2.5) may also be emitted." We also see a discussion of aqueous ammonia and some of the emergency planning regulatory structure.

**Exhibit 3** consists of two pages from the SARA Title III List of Lists, which shows the regulatory status of each chemical considered especially hazardous under our federal chemical emergency laws.

The first page shows the three listings for ammonia. There is sometimes confusion about ammonia because of the three listings. The anhydrous ammonia has a 10,000 pound threshold under the Clean Air Act 112r Risk Management Program. A facility must have 20,000 pounds of ammonia (concentrations 20% or greater) before it has to prepare a Clean Air Act 112r Risk Management Plan.

The first listing for ammonia does not have a value in the Clean Air Act 112r Risk Management Program column because this is the catchall for all other types of ammonia (lower concentrations than 20%), but you will notice it has the same values as any of the other forms of ammonia in the CERCLA RQ, EHS RQ, and Section 302 EHS TPQ columns. A facility has to compute the amount of ammonia on-site by weight to determine how much aggregate ammonia is on-site. The next version of this reference book is under development now, and likely will clear up this confusion about aqueous ammonia at less than 20% concentrations.

I will note again that ammonia, aqueous or anhydrous, is regulated as a CERCLA Hazardous Substance. Even Ammonium Hydroxide, which some try to say is aqueous ammonia, is regulated by CERCLA. A 1,000 pound release of ammonium hydroxide must be immediately reported to the federal, state, county, and local government.

The exhibits I provided earlier when I testified were drawn from 20,000 pound spill of ammonia. The CAMEO/ALOHA software uses algorithms based on a chemical's behavior when spilled. Aqueous ammonia can be especially dangerous because it will look just like water at first glance, but as the water evaporates, it can suddenly flash boil and seem to explode into the air. When fighting a spill of anhydrous ammonia, the responders will spray water on the cloud to knock it down, but will have to pump this now aqueous ammonia solution into a tank before the water evaporates and starts releasing ammonia fumes again.

**Exhibit 4** is five (5) pages from the Harquahala Generating Company, LLC air permit application. Here you will see a discussion of control technologies, including SCONOX and SCR. You will also see an economic viability discussion. Just a few years ago, SCR was only being used on smaller generating facilities.

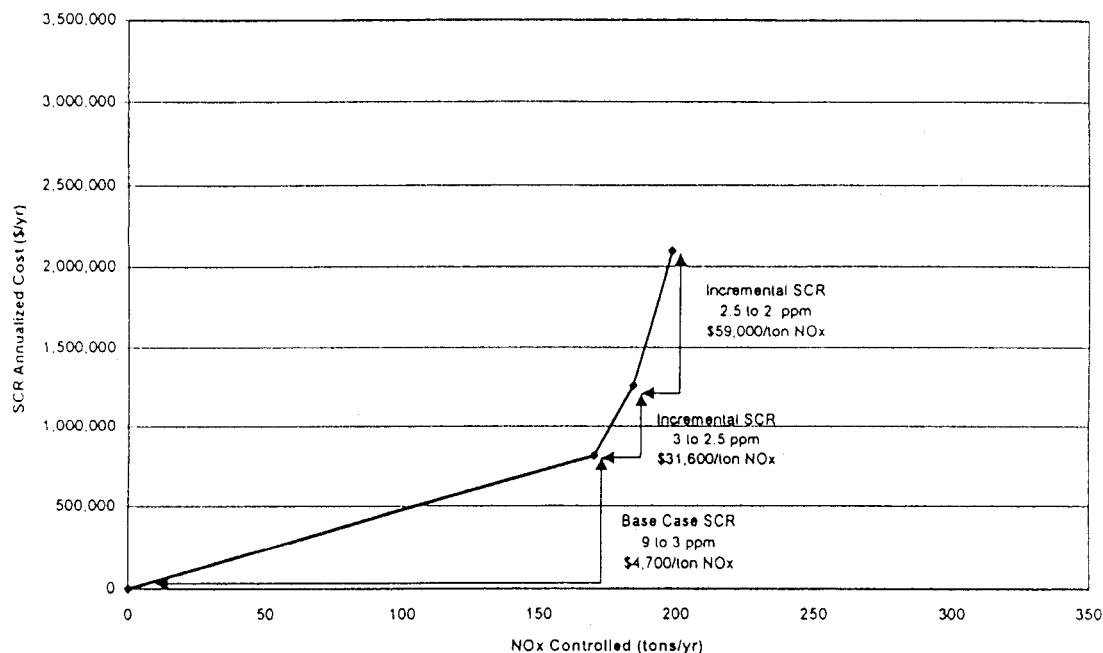
**Exhibit 5** is four (4) pages printed off from the SCONOX website, which is located at [http://www.glet.com/pr\\_sconox.htm](http://www.glet.com/pr_sconox.htm)

Evidently, there is no obstacle to using this technology for even 300 MW power generating facilities. If someone told you that the technology can't be used on large power plants, they are misinformed.

## Exhibit 1

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### AVEP Incremental NOx Control Evaluation



### Relative Ammonia Slip Levels

Reductions in NOx below those proposed would result in greater emissions of ammonia ( $\text{NH}_3$ ) to the environment. Since no SCR system has yet to acquire long-term continuous compliance experience at these emission levels, it is difficult to precisely quantify how much additional ammonia would actually be emitted as a result of decreasing the AVEP NOx emission limit from 3 ppm to 2.5 or 2 ppm.

To describe the phenomenon of ammonia slip, let us first consider the Chemical Engineering kinetics of an SCR system. The governing chemical reaction requires one Mol (a quantity expressed on a molecular level) of  $\text{NH}_3$  to remove one Mol of NOx. This is referred to as a 1:1 Molar ratio. Molecular theory says that if we combine one Mol of  $\text{NH}_3$  and one Mol of NOx, provide perfect mixing and an infinite reaction time, all of the NOx and all of the  $\text{NH}_3$  will be converted to Nitrogen and water. In this theoretical reaction, NOx emissions would be zero and there would be no slip.

In a real world-turbine application, we do not have infinite time for the reaction to complete. In fact, gas residence time in the HRSG is estimated at less than one second. For this reason, SCR catalyst is added to speed up the reaction, so as to enable appreciable conversion efficiency in the time available.

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The second ideal world assumption in the theoretical model is ideal mixing. Again, we have much less than a second to exactly match every molecule of NO<sub>x</sub> to one molecule of NH<sub>3</sub>, over the entire HRSG cross section (several hundred square feet). In ultra-low NO<sub>x</sub> applications, engineers expend much effort on computer flow modeling and design of the NH<sub>3</sub> injection grid, not just to evenly distribute NH<sub>3</sub>, but to actually try to map locations of more or less NO<sub>x</sub> and inject more or less NH<sub>3</sub> locally. In the real world, injection at a 1:1 molar ratio results in emissions of unreacted NO<sub>x</sub> and unreacted NH<sub>3</sub> being emitted from the stack due to reaction and mixing time limitations. To achieve NO<sub>x</sub> emissions in the 3 ppm range, it is necessary to over-inject NH<sub>3</sub> at a molar ratio greater than 1:1. This results in NH<sub>3</sub> slip of up to 10 ppm as the catalyst ages.

To date, the real world limitation of SCR technology performance is about 2 ppm. To achieve lower NO<sub>x</sub> levels additional catalyst thickness is required, and a more elaborate NH<sub>3</sub> injection grid is provided.

Consider the additional NO<sub>x</sub> to NH<sub>3</sub> mixing problem of changing turbine loads and varying levels of duct firing. As turbine load varies, the flow dynamics in the HRSG change, with the result that the mapped areas of higher NO<sub>x</sub> concentration may not be in the same location as where the computer designed NH<sub>3</sub> distribution grid is injecting. As the flow distribution changes with load, NO<sub>x</sub> emissions will increase; the NH<sub>3</sub> injection grid design is at best an engineering compromise.

Now consider duct firing. Duct firing not only changes the NO<sub>x</sub> distribution again, but now almost doubles the amount of NO<sub>x</sub> to be reacted. Again, the injection grid cannot distribute the NH<sub>3</sub> optimally under every condition. A system with a lower NO<sub>x</sub> emission limit has no other recourse than to inject greater molar ratios of NH<sub>3</sub>, which results in fundamentally more NH<sub>3</sub> slip.

Specific to AVEP, at 3 ppm we are already pushing the limits of SCR technology. As discussed previously, with a 3 ppm limit our system may actually have to operate around 2.5 ppm given potential CEM accuracy limitations, to account for load and temperature changes, to avoid nuisance exceedences, and to have enough operating margin below the continuous compliance limit to allow the operators to recover a three-hour average after a spike. On top of that, the duct burner itself contributes almost 1 ppm; therefore, the SCR system for AVEP must already be designed to be capable of less than 2 ppm NO<sub>x</sub> (steady state turbine operation at injection grid design point, no duct firing, no CEM error). The AVEP is already at the current demonstrated performance limitation of SCR technology.

Any further reductions in NO<sub>x</sub> emission limits would require yet more catalyst and a higher molar ratio of NH<sub>3</sub>:NO<sub>x</sub>. This will fundamentally result in greater ammonia slip emissions to the atmosphere as the operators try to overdrive the NH<sub>3</sub>/NO<sub>x</sub> reaction to lower NO<sub>x</sub> levels at the expense of greater slip. Additionally, more catalyst would result in more pressure drop and lower system efficiency. Fewer megawatts would be produced from AVEP; this lost capacity would have to be made up from some other, probably dirtier, powerplant. Setting a NO<sub>x</sub> limit lower than 3 ppm would therefore result in additional emissions of NH<sub>3</sub> (a PM<sub>10</sub> precursor) as well as additional collateral emissions of NO<sub>x</sub>, PM<sub>10</sub>, VOC, CO and SO<sub>2</sub> to produce the wasted power from some other Arizona power plant.

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Part of the difficulty in quantifying how much additional slip would be emitted is that this has never been demonstrated-in-practice on an equivalent system. Also,  $\text{NH}_3$  slip levels vary with catalyst age. Actual ammonia slip levels for a new unit are typically relatively low. However, as the SCR system ages and physical and chemical poisoning occur, the SCR catalyst will gradually deactivate, and more and more ammonia injection (and resulting slip) is required just to maintain the design  $\text{NO}_x$  emission levels. When the  $\text{NH}_3$  slip limit is met, the only recourse is to replace the catalyst.

While it is possible to obtain vendor guarantees for a steady state, initial compliance test at various  $\text{NO}_x$  levels and ammonia slip, the risk of failure increases as enforceable continuous emission limits contained in a permit for  $\text{NO}_x$  and/or slip decrease. As discussed previously, there are no systems that are currently operating at these LAER  $\text{NO}_x$  levels, and the actual slip history and catalyst life have yet to be experienced.

#### Permitted Westbrook VOC Levels

Investigation of the 0.4 ppm VOC level in the EPA BACT Clearinghouse for the Westbrook project has been determined to be an error. The Westbrook Power project will have two GE 7FA combined-cycle units with unfired HRSGs. The units will have dry low  $\text{NO}_x$  (DLN) combustors with SCR but without an oxidation catalyst. The permit contains a VOC limit of 3 lbs/hr, which is estimated to be about 1.2 ppm. Compliance for the VOC limit is determined with an initial source test only.

#### Permitted Duke $\text{PM}_{10}$ Levels

Duke Energy has permitted 6 combined-cycle plants in the U.S. in the last couple of years. All six projects will use GE 7FA turbines and were permitted with a  $\text{PM}_{10}$  limit of 18 lbs/hr, including back half particulates. None of these plants will have duct firing. Although the applications did not originally include SCR, SCR systems were later agreed to during the permitting process for two of these facilities in Mississippi. It appears that the additional  $\text{PM}_{10}$  emissions due to the SCR system was not taken into account in developing the permit limits for these two plants.

#### Review of GE $\text{PM}_{10}$ Guarantee

Based on the discussion with MCESD, Duke Energy requested that GE reconsider their guarantee of 20 lbs/hr from the turbine in light of the County's concerns. GE re-evaluated the number based on the maximum sulfur content for this project (0.75 gr/100dscf), and concluded that the guarantee could be reduced to 19 lbs/hr. This number is somewhat higher than previous  $\text{PM}_{10}$  emission rates for the turbines provided by GE. The previous emission rates were developed through a more informal process when inclusion of back-half condensables came up. Additional data have since been gathered by GE and they now are using a formula which takes into account the amount of sulfur in the fuel.

The Pinnacle West (PNW) application was reviewed in light of the discussion regarding the  $\text{PM}_{10}$  limit. The  $\text{PM}_{10}$  limit proposed for PNW is 30.35 lbs/hr, 25 lbs/hr from the turbines and SCR, and 5.35 lbs/hr from the duct burners. This proposed rate is very similar to the 31 lbs/hr now proposed for AVEP.

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December 28, 1999  
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## PM 10 Emissions

Comment: The application proposes an emission limit of 32 pounds per hour from each combustion turbine (including duct burners). As we understand the information provided regarding fuel flow rate, this equates to approximately 0.015 lbs/mmBtu. The application states that there is no technically feasible post-combustion control system for PM-10 emission reductions. That may be the case, however, the inlet air filter should help reduce PM-10 emissions and could be considered part of the BACT determination. If the inlet air filter is used as part of an emission control system, can PM-10 emissions be reduced to 0.007 lb/mmBtu?

Response: *The project as proposed already includes an inlet air filter; the lowest emission rate of PM<sub>10</sub> guaranteed by GE and ABB includes this reduction. We caution that care must be exercised in comparing PM<sub>10</sub> emission rates in the Clearinghouse. Historically, turbine PM<sub>10</sub> has been expressed as front half catch only (EPA Reference Method 5). Since 1998, it has been EPA policy to express PM<sub>10</sub> as front and back half (including condensables) using EPA Reference Methods 5 and 202. This approximately doubles the amount of PM<sub>10</sub> reported. Because this requirement is relatively new, there is a dearth of data and what data are available show a wide level of variability. Secondly, PM<sub>10</sub> emissions so expressed are really a function of firing rate; substantial duct firing can double the hourly emissions. Finally, no CEM's exists to capture real-time data of PM<sub>10</sub> emissions. Therefore, the only testing that has been performed for these units are "snapshot" stack compliance tests, which have indicated a high level of variability among units. For purposes of establishing continuous compliance limits and manufacturer's guarantees, the highest (rather than the average or mean) of these data points are used. This may result in emission rate variations from engine to engine, or manufacturer to manufacturer. This is the basis for the proposed emission values, which equate to a combined front half/back half PM<sub>10</sub> emission rate, including PM<sub>10</sub> from the turbines, duct burners and SCR systems.*

Comment: There was no discussion in the application of the emission rate of PM-10 associated with ammonia slip as opposed to combustion alone. Please provide information regarding the ammonia slip-associated PM-10 emissions compared to the combustion related emissions (including inlet air particulate). It is our understanding that the proposed 32 pounds per hour per turbine includes ammonia slip-related PM-10 as well as combustion related PM-10. It would be helpful to know the relative amount of those two emission types (ammonia slip related and combustion related).

Response: *PM<sub>10</sub> associated with ammonia slip is included in the proposed PM<sub>10</sub> emission limit. These total emissions were included in the air dispersion modeling analysis performed. PM<sub>10</sub> emissions from the turbines are guaranteed by GE to be 20 lbs/hr from each gas turbine. The ABB guaranteed level from the duct burners and operation of the SCR system added another 12 lbs/hr per unit. The ABB estimate is based on a worst case assumption that, if all of the fuel sulfur is converted to ammonium bisulfate, the back half condensable particulates would be 8 lbs/hr. The duct burners contribute up to an additional 4 lbs/hr per HRSG (based on an emission rate of 0.01 lb/MMBtu, HHV), for a worst case total of 12 lbs/hr. In actuality, it is highly unlikely that all of the fuel sulfur will be converted.*

## Exhibit 2



## Economic Evaluation

Since GE cannot provide cost data, and since XONON™ combustors are not offered commercially for the turbines in the size range selected for Arlington Valley Energy, an economic analysis could not be performed.

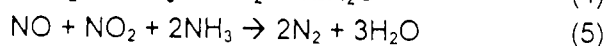
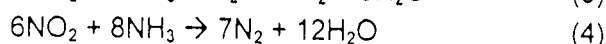
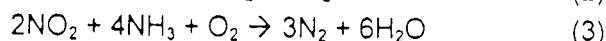
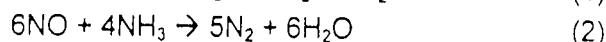
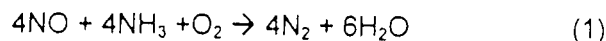
### Summary

XONON™ is not an available control technology for Arlington Valley Energy.

#### 4.3.2.3 Selective Catalytic Reduction (SCR)

##### Technical Analysis

Selective catalytic reduction (SCR) is a process that involves post-combustion removal of NO<sub>x</sub> from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions (Cho, 1994):



The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO<sub>x</sub> decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, ammonia slip emissions, and design of the NH<sub>3</sub> injection system.

Three types of catalyst bed configurations have been successfully applied to commercial sources: the moving bed reactor, the parallel flow reactor, and the fixed bed reactor. The fixed bed reactor is applicable to sources with little or no particulate present in the flue gas, such as would be the case for the proposed gas turbines. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow within the HRSG and transport of the reactants to the active catalyst sites takes place through a combination of diffusion and convection.

Optimum operating temperature for a vanadium-titanium catalyst system has been shown to be in the range of 550° to 800°F (Rogers, 1992). In applications where heat recovery steam generation is used, SCR catalyst and ammonia injection grids are typically installed between tube bundles

within the HRSG where the flue gas temperature remains within the required temperature range during base load operation. Operation at part load and potentially with or without duct burners during start-up and shut-down, yields a decreased  $\text{NO}_x$  conversion efficiency and a non-optimum SCR temperature. Since operation at less than design temperatures would neither effectively remove  $\text{NO}_x$  nor reduce ammonia, both would be emitted from the stack during off design catalyst temperatures. For this reason, automatic controls are used to cut back ammonia feed when the catalyst bed is below set point temperature.

Sulfur content of the fuel can be a concern for systems that employ SCR, however the pipeline quality natural gas maximum for this facility (0.75 grains per 100 dscf) should afford reasonable catalyst life. Catalyst systems promote partial oxidation of sulfur dioxide (from trace sulfur in gas and the mercaptans used as an odorant) to sulfur trioxide ( $\text{SO}_3$ ), which combines with water to form sulfuric acid. At the temperatures of the HRSG,  $\text{SO}_3$  and sulfuric acid may react with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled in the HRSG, or may be emitted from the stack as increased emissions of  $\text{PM}_{10}$ . Sulfates and nitrates emitted from the stack are also precursors to atmospheric formation of  $\text{PM}_{10}$ . Under some circumstances, fouling may eventually lead to increased system pressure drop over time and decreased heat transfer efficiencies. Fortunately, ammonium salts may be removed by water washing, although this process requires an outage to allow cooling, washing and restart of the system.

The SCR process may also be subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically only guarantee a 3-year lifetime to very low emission level, high performance catalyst systems.

SCR manufacturers typically estimate 10-20 ppm of unreacted ammonia emissions (ammonia slip) when making  $\text{NO}_x$  control guarantees at very low emissions levels. To achieve low  $\text{NO}_x$  limits, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which necessarily results in ammonia slip. Thus an emissions trade-off between  $\text{NO}_x$  and ammonia may occur in high  $\text{NO}_x$  reduction applications.

### Economic Evaluation

An economic evaluation was performed and determined that SCR at 3 ppm  $\text{NO}_x$  is cost effective for Arlington Valley Energy. However, lower levels such as 2.5 ppm or 2.0 ppm are not. The following describes the analysis that lead to these conclusions.

▪ **Relative Ammonia Slip Levels**

For this project, an ammonia slip of 10 ppm is proposed. Reductions in NOx below 3 ppm would result in greater emissions of ammonia (NH<sub>3</sub>) to the environment. Since no SCR system has yet to acquire long-term continuous compliance experience at these emission levels, it is difficult to precisely quantify how much additional ammonia would actually be emitted as a result of decreasing the AVEP NOx emission limit from 3 ppm to 2.5 or 2 ppm.

To describe the phenomenon of ammonia slip, let us first consider the Chemical Engineering kinetics of an SCR system. The governing chemical reaction requires one Mol (a quantity expressed on a molecular level) of NH<sub>3</sub> to remove one Mol of NOx. This is referred to as a 1:1 Molar ratio. Molecular theory says that if we combine one Mol of NH<sub>3</sub> and one Mol of NOx, provide perfect mixing and an infinite reaction time, all of the NOx and all of the NH<sub>3</sub> will be converted to Nitrogen and water. In this theoretical reaction, NOx emissions would be zero and there would be no slip.

In a real world-turbine application, we do not have infinite time for the reaction to complete. In fact, gas residence time in the HRSG is estimated at less than one second. For this reason, SCR catalyst is added to speed up the reaction, so as to enable appreciable conversion efficiency in the time available.

The second ideal world assumption in the theoretical model is ideal mixing. Again, we have much less than a second to exactly match every molecule of NOx to one molecule of NH<sub>3</sub>, over the entire HRSG cross section (several hundred square feet). In ultra-low NOx applications, engineers expend much effort on computer flow modeling and design of the NH<sub>3</sub> injection grid, not just to evenly distribute NH<sub>3</sub>, but to actually try to map locations of more or less NOx and inject more or less NH<sub>3</sub> locally. In the real world, injection at a 1:1 molar ratio results in emissions of unreacted NOx and unreacted NH<sub>3</sub> being emitted from the stack due to reaction and mixing time limitations. To achieve NOx emissions in the 3 ppm range, it is necessary to over-inject NH<sub>3</sub> at a molar ratio greater than 1:1. This results in NH<sub>3</sub> slip of up to 10 ppm as the catalyst ages.

To date, the real world limitation of SCR technology performance is about 2 ppm. To achieve lower NOx levels additional catalyst thickness is required, and a more elaborate NH<sub>3</sub> injection grid is provided.

Consider the additional NOx to NH<sub>3</sub> mixing problem of changing turbine loads and varying levels of duct firing. As turbine load varies, the flow dynamics in the HRSG change, with the result that the mapped areas of higher NOx concentration may not be in the same location as where the

computer designed  $\text{NH}_3$  distribution grid is injecting. As the flow distribution changes with load,  $\text{NO}_x$  emissions will increase; the  $\text{NH}_3$  injection grid design is at best an engineering compromise.

Now consider duct firing. Duct firing not only changes the  $\text{NO}_x$  distribution again, but now almost doubles the amount of  $\text{NO}_x$  to be reacted. Again, the injection grid cannot distribute the  $\text{NH}_3$  optimally under every condition. A system with a lower  $\text{NO}_x$  emission limit has no other recourse than to inject greater molar ratios of  $\text{NH}_3$ , which results in fundamentally more  $\text{NH}_3$  slip.

Specific to AVEP, at 3 ppm we are already pushing the limits of SCR technology. As discussed previously, with a 3 ppm limit our system may actually have to operate around 2.5 ppm given potential CEM accuracy limitations, to account for load and temperature changes, to avoid nuisance exceedences, and to have enough operating margin below the continuous compliance limit to allow the operators to recover a three-hour average after a spike. On top of that, the duct burner itself contributes almost 1 ppm; therefore, the SCR system for AVEP must already be designed to be capable of less than 2 ppm  $\text{NO}_x$  (steady state turbine operation at injection grid design point, no duct firing, no CEM error). The AVEP is already at the current demonstrated performance limitation of SCR technology.

Any further reductions in  $\text{NO}_x$  emission limits would require yet more catalyst and a higher molar ratio of  $\text{NH}_3/\text{NO}_x$ . This will fundamentally result in greater ammonia slip emissions to the atmosphere as the operators try to overdrive the  $\text{NH}_3/\text{NO}_x$  reaction to lower  $\text{NO}_x$  levels at the expense of greater slip. Additionally, more catalyst would result in more pressure drop and lower system efficiency. Fewer megawatts would be produced from AVEP; this lost capacity would have to be made up from some other, probably dirtier, powerplant. Setting a  $\text{NO}_x$  limit lower than 3 ppm would therefore result in additional emissions of  $\text{NH}_3$  (a  $\text{PM}_{10}$  precursor) as well as additional collateral emissions of  $\text{NO}_x$ ,  $\text{PM}_{10}$ , VOC, CO and  $\text{SO}_2$  to produce the wasted power from some other Arizona power plant.

Part of the difficulty in quantifying how much additional slip would be emitted is that this has never been demonstrated-in-practice on an equivalent system. Also,  $\text{NH}_3$  slip levels vary with catalyst age. Actual ammonia slip levels for a new unit are typically relatively low. However, as the SCR system ages and physical and chemical poisoning occur, the SCR catalyst will gradually deactivate, and more and more ammonia injection (and resulting slip) is required just to maintain the design  $\text{NO}_x$  emission levels. When the  $\text{NH}_3$  slip limit is met, the only recourse is to replace the catalyst.

While it is possible to obtain vendor guarantees for a steady state, initial compliance test at various  $\text{NO}_x$  levels and ammonia slip, the risk of failure increases as enforceable continuous

emission limits contained in a permit for NO<sub>x</sub> and/or slip decrease. As discussed previously, there are no systems that are currently operating at these LAER NO<sub>x</sub> levels, and the actual slip history and catalyst life have yet to be experienced.

### Environmental Impacts

The potential environmental impacts associated with the use of SCR are summarized below:

- Some unreacted ammonia would be emitted to the atmosphere (ammonia slip); ammonia is a PM<sub>10</sub> (and PM<sub>2.5</sub>) precursor. Ammonia salts (PM<sub>10</sub>/PM<sub>2.5</sub>) may also be emitted; and
- There are safety issues associated with the transportation, handling, and storage of aqueous ammonia albeit manageable ones. The storage of aqueous ammonia (which is substantially lower risk than for anhydrous ammonia) is regulated under Occupational Safety and Health Act (OSHA) regulations and the Risk Management Planning (RMP) provisions of Clean Air Act Amendments Title III, Section 112(r).

The transport, handling, and storage of aqueous ammonia presents some limited environmental risks. However, the benefits from reduced NO<sub>x</sub> emissions, including the reduction in NO<sub>x</sub> precursor effects on ozone and visibility, should outweigh the potential environmental impacts from the storage and handling of aqueous ammonia at Arlington Valley Energy.

### Summary

The proposed limit of 3 ppm NO<sub>x</sub> assumes that "uncontrolled" emissions from the turbine will be at 9 ppm as guaranteed by GE. While AVEP acknowledges that 9 ppm can be maintained from the turbine on an annual average basis, short term NO<sub>x</sub> emissions from DLN combustors are known to "bounce around" due to perturbations caused by transient or changing conditions such as load, temperature and humidity. Since the 3 ppm value proposed is a short-term (three-hour) limit, this means that the compliance limit must include sufficient margin to accommodate higher short term DLN emissions. If DLN NO<sub>x</sub> were to temporarily climb to 11 ppm during a sudden load change, this could result in an additional ~ ½ ppm of NO<sub>x</sub> downstream of the SCR. It can be seen that the proposed limit of 3 ppm would allow an SCR designed for 2.5 ppm to accommodate this inherent dry low-NO<sub>x</sub> short-term variability.

SCR has become a widely accepted control technology for application to combined-cycle turbines. While SCONO<sub>x</sub> may be capable of slightly lower emission rates (i.e., as low as 2 ppm vs. 3 ppm proposed with SCR) it has yet to be scaled up and applied to a project of this scale, and it is also not cost effective. While some recent permits in non-attainment areas have been written at 2 and 2.5 ppm with SCR (as LAER), these levels have yet to be demonstrated-in-practice for

## Exhibit 3

## Section 304

Number	Chemical Name	Sec. 302 (EHS) TPO	EHS RO	CERCLA RO	CAA 112(r) TO	Sec 313	RCRA CODE
15-57-5	Ferric ammonium citrate			1,000			
14-65-6	Dichlobenil			100			
10-71-6	Xylenol			1,000			
13-28-2	Arsenic pentoxide	100/10,000	1	1			P011
13-32-8	Arsenic disulfide			1			
13-33-9	Arsenic trisulfide			1			
16-19-0	Cadmium oxide	100/10,000	100				
19-64-4	Antimony trioxide			1,000			
10-58-3	Potassium hydroxide			1,000			
10-73-2	Sodium hydroxide			1,000			
13-27-5	Molybdenum trioxide					313	
14-20-1	Thorium dioxide					313	
14-32-5	Thallic oxide			100			P113
14-62-1	Vanadium pentoxide	100/10,000	1,000	1,000			P120
14-80-3	Sulfur phosphide			100			U189
14-84-7	Zinc phosphide	500	100	100			P122
14-84-7	Zinc phosphide (conc. > 10%)	500	100	100			P122
14-84-7	Zinc phosphide (conc. <= 10%)	500	100	100			U249
14-87-0	Lead sulfide			10			
19-72-8	2,4,5-T amines			5,000			
19-77-3	Cresol (mixed isomers)			100		313	U052
20-18-9	2,4-D Esters			100		X	
20-18-9	2,4-D propylene glycol butyl ether ester			100		313	
21-12-6	Nitrotoluene			1,000			
27-52-2	Arsenic acid			1			
27-53-3	Arsenic trioxide	100/10,000	1	1			P012
27-53-3	Arsenous oxide	100/10,000	1	1			P012
330-20-7	Xylene (mixed isomers)			100		313	U239
332-07-6	Zinc borate			1,000			
332-21-4	Asbestos (friable)			1		313	
333-74-0	Hydrogen				10,000		
333-83-1	Sodium bifluoride			100			
335-32-6	Lead subacetate			10			U146
335-87-1	Hexachloronaphthalene					313	
336-21-6	Ammonium hydroxide			1,000			
336-36-3	PCBs			1		X	
336-36-3	Polychlorinated biphenyls			1		313	
338-23-4	Methyl ethyl ketone peroxide			10			U160
338-24-5	Naphthenic acid			100			
341-49-7	Ammonium bifluoride			100			
1344-28-1	Aluminum oxide (fibrous forms)					313	
1397-94-0	Antimycin A	1,000/10,000	1,000				
1420-07-1	Dinoterb	500/10,000	500				
1464-53-5	2,2'-Bioxirane	500	10	10		X	U085
1464-53-5	Diepoxybutane	500	10	10		313	U085
1558-25-4	Trichloro(chloromethyl)silane	100	100				
1563-38-8	Carbofuran phenol			1*			U367
1563-66-2	Carbofuran	10/10,000	10	10		313	P127
1582-09-8	Benzeneamine, 2,6-dinitro-N,N-dipropyl-4-(trifluoro			10		X	
1582-09-8	Trifluralin			10		313	

RCRA carbamate waste; statutory one-pound RQ applies until RQs are adjusted.

## Section 304

CAS Number	Chemical Name	Sec. 302 (EHS) TPO	EHS RO	CERCLA RO	CAA 112(r) TO	Sec 313	RCRA CODE
7558-79-4	Sodium phosphate, dibasic			5,000			
7580-67-8	Lithium hydride	100	100				
7601-54-9	Sodium phosphate, tribasic			5,000			
7631-89-2	Sodium arsenate	1,000/10,000	1	1			
7631-90-5	Sodium bisulfite			5,000			
7632-00-0	Sodium nitrite			100		313	
7637-07-2	Borane, trifluoro-	500	500		5,000	X	
7637-07-2	Boron trifluoride	500	500		5,000	313	
7645-25-2	Lead arsenate			1			
7646-85-7	Zinc chloride			1,000			
7647-01-0	Hydrochloric acid			5,000			
7647-01-0	Hydrochloric acid (conc 37% or greater)			5,000	15,000		
7647-01-0	Hydrochloric acid (aerosol forms only)			5,000		313	
7647-01-0	Hydrogen chloride (anhydrous)	500	5,000	5,000	5,000	X	
7647-01-0	Hydrogen chloride (gas only)	500	5,000	5,000	5,000	X	
7647-18-9	Antimony pentachloride			1,000			
7664-38-2	Phosphoric acid			5,000		313	
7664-39-3	Hydrofluoric acid	100	100	100		X	U134
7664-39-3	Hydrofluoric acid (conc. 50% or greater)	100	100	100	1,000	X	U134
7664-39-3	Hydrogen fluoride	100	100	100		313	U134
7664-39-3	Hydrogen fluoride (anhydrous)	100	100	100	1,000	X	U134
7664-41-7	Ammonia	500	100	100		313	
7664-41-7	Ammonia (anhydrous)	500	100	100	10,000	X	
7664-41-7	Ammonia (conc 20% or greater)	500	100	100	20,000	X	
7664-93-9	Sulfuric acid	1,000	1,000	1,000			
7664-93-9	Sulfuric acid (aerosol forms only)	1,000	1,000	1,000		313	
7681-49-4	Sodium fluoride			1,000			
7681-52-9	Sodium hypochlorite			100			
7696-12-0	2,2-Dimethyl-3-(2-methyl-1-propenyl)cyclopropaneca					X	
7696-12-0	Tetramethrin					313	
7697-37-2	Nitric acid	1,000	1,000	1,000		313	
7697-37-2	Nitric acid (conc 80% or greater)	1,000	1,000	1,000	15,000	X	
7699-45-8	Zinc bromide			1,000			
7705-08-0	Ferric chloride			1,000			
7718-54-9	Nickel chloride			100			
7719-12-2	Phosphorous trichloride	1,000	1,000	1,000	15,000		
7719-12-2	Phosphorus trichloride	1,000	1,000	1,000	15,000		
7720-78-7	Ferrous sulfate			1,000			
7722-64-7	Potassium permanganate			100			
7722-84-1	Hydrogen peroxide (Conc. > 52%)	1,000	1,000				
7723-14-0	Phosphorus (yellow or white)	100	1	1		313	
7723-14-0	Phosphorus	100	1	1			
7726-95-6	Bromine	500	500		10,000	313	
7733-02-0	Zinc sulfate			1,000			
7738-94-5	Chromic acid			10			
7758-01-2	Potassium bromate					313	
7758-29-4	Sodium phosphate, tribasic			5,000			
7758-94-3	Ferrous chloride			100			
7758-95-4	Lead chloride			10			
7758-98-7	Cupric sulfate			10			



## Exhibit 4

Based on a review of the materials described above, the following NO<sub>x</sub> control technologies were determined to be technically feasible and were evaluated (presented in order of most to least effective):

- XONON™
- SCONO<sub>x</sub>™
- DLN and SCR
- Water/Steam Injection and SCR
- DLN
- Water/Steam Injection

**XONON™.** Catalytica's XONON™ combustion system improves the combustion process by lowering the peak combustion temperature to reduce the formation of NO<sub>x</sub> while also providing further control of CO and UHC emissions that other NO<sub>x</sub> control technologies (such as water injection and DLN) can not provide. Most gas turbine emission control technologies remove air contaminants from exhaust gas prior to release to the atmosphere. In contrast, the overall combustion process in the XONON™ system is a partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. In the catalyst module, a portion of the fuel is combusted without a flame (i.e., at relatively low temperature) to produce a hot gas. A homogeneous combustion region is located immediately downstream where the remainder of the fuel is combusted.

The key feature of the XONON™ combustion system is a proprietary catalytic component, called the XONON™ Module, which is integral to the gas turbine combustor. XONON™ combusts the fuel without a flame, thus eliminating the peak flame temperatures that lead to NO<sub>x</sub>. Turbine performance is not affected.

XONON™ is an innovative technology that is currently being commercialized on smaller-scale projects with support from the U.S. Department of Energy, the California Energy Commission (CEC), and CARB. The CARB has reported on the pilot effort underway in Santa Clara where the XONON™ system is operating at a 1.5-MW simple-cycle pilot facility. The CARB indicated in its June 1999 Stationary Source Division Report *Guidance for Power Plant Siting and Best Available Control Technology* (CARB, 1999), page 23: "Emission levels from 1.33 to 4.04 ppmvd NO<sub>x</sub> at 15 percent oxygen (O<sub>2</sub>) have been achieved at Silicon Valley Power utilizing the XONON™ technology." But they further indicate that "there is not sufficient operating experience to ensure reliable performance on large gas turbines."

XONON™ does not represent an available control technology for any 170 MW F-Class turbine. According to Catalytica, a joint venture agreement is in place with General Electric (GE) to eventually develop XONON™ as Original Equipment Manufacturer (OEM) and retrofit equipment for the entire GE turbine line. It is critical to note that GE does not currently offer a XONON™ combustor option for 7FA or any other large industrial turbine. Recently, an Application for Certification was filed with the California Energy Commission for the Pastoria Energy Facility Project (November 1999) which proposes to install XONON™ on F-Class

Turbines if the technological issues can be resolved. The NO<sub>x</sub> emissions limit proposed for the Pastoria Project is being evaluated under LAER criteria. DLN/SCR is proposed as the back-up control technology if the XONON™ technology proves infeasible for this project. Therefore, XONON™ does not represent a currently available control technology for the Harquahala Generating Project under BACT evaluation criteria.

**SCONO<sub>x</sub>™.** SCONO<sub>x</sub>™ is a new innovative post-combustion control system produced by Goal Line Environmental Technologies that began commercial operation at the Federal Plant in Vernon, California in December 1996. The Federal Plant is owned by Sunlaw Cogeneration Partners and consists of an LM2500 combustion turbine (approximately 28 MW) with a HRSG. The unit is roughly one-sixth the size of F-Class combustion turbines. The SCONO<sub>x</sub>™ system uses a coated oxidation catalyst installed in the flue gas to remove both NO<sub>x</sub> and CO without a reagent such as ammonia. The NO emissions are oxidized to NO<sub>2</sub> and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically. This gas de-absorbs the NO<sub>2</sub> from the catalyst and reduces it to N<sub>2</sub> prior to exit from the stack. CO is oxidized to CO<sub>2</sub> and exits the stack, and VOC is reduced as well.

SCONO<sub>x</sub>™ operates in a temperature range between 300° F and 700° F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, NO<sub>2</sub> is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regenerative gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. As a result, each section of the catalyst is regenerated about once every fifteen minutes.

Current emissions data show that the Federal Plant is controlling NO<sub>x</sub> emissions to 2 ppmvd (at 15 percent O<sub>2</sub>) on a periodic basis for an LM2500 application (excluding start-up, shutdown, and frequent maintenance). SCONO<sub>x</sub>™ is promising technology, but it has not been achieved in practice for large-class combustion turbines. Nonetheless, the SCONO<sub>x</sub>™ system offers the potential for significant environmental benefits if it can be used on large turbines. The system may be able to achieve NO<sub>x</sub> levels below current LAER and BACT levels, and CO levels of 6 ppmvd (at 15 percent O<sub>2</sub>) for turbine load conditions greater than 73 percent (10 ppmvd (at 15 percent O<sub>2</sub>) for low load conditions).

At the time of this filing, ABB and Goal Line have entered into an agreement to make SCONO<sub>x</sub>™ commercially available for an F-Class ABB turbine at a guaranteed emissions level of 2.5 ppmvd NO<sub>x</sub> (at 15 percent O<sub>2</sub>). To date, SCONO<sub>x</sub>™ has not been achieved in practice on an F-Class or G-Class turbine.

The La Paloma Generating Project in California initially proposed to demonstrate the viability of SCONO<sub>x</sub>™ on one ABB KA-24 (150 MW) turbine at the facility assuming that the technological and commercial availability issues could be resolved. The NO<sub>x</sub> emissions limit to be met by

either SCONO<sub>x</sub><sup>TM</sup> or DLN/SCR was approved under LAER criteria. Commercial, warranty, and operational issues of concern for SCONO<sub>x</sub><sup>TM</sup> were not resolved by the final engineering design deadline, so as provided for in the permit approval of this project, DLN/SCR will be installed for NO<sub>x</sub> control.

Otay Mesa Generating Company LLC, an affiliate of Harquahala Generating Company, LLC, has recently (August 1999) submitted an Application for Certification to the California Energy Commission for the Otay Mesa Project which proposes to install SCONO<sub>x</sub><sup>TM</sup> anticipating that commercial, warranty, and operational issues of concern may be resolved in time for that facility's construction. The NO<sub>x</sub> emissions limit proposed for the Otay Mesa Project is being evaluated under LAER criteria. DLN/SCR is proposed as the back-up control technology if the SCONO<sub>x</sub><sup>TM</sup> technology proves infeasible for this project.

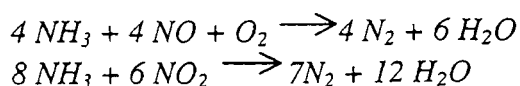
As of this writing, SCONO<sub>x</sub><sup>TM</sup> has been represented as currently available control technology. It has not been achieved in practice on an F-Class or G-Class turbine, and with no financial guarantees for performance to date, these unknowns represent a level of risk that would alter the current ability to reasonably finance the project. Should the commercial, warranty, and operational issues of concern be resolved with ABB, this technology could be considered for implementation; thus a cost analysis has been performed to assess its potential cost feasibility. The purchased equipment cost was scaled-up from an ABB cost estimate for a GT-24 engine submitted in support of a recent permit application to the Michigan Department of Environmental Quality (MDEQ) (Earth Tech 2000). This project is also being permitted at 2.5 ppm. The scale-up factors used for the 501G turbine are described in Tables 4-3 and 4-4 footnotes. Other cost estimate factors were obtained from the MDEQ application support materials (Earth Tech 2000). Table 4-3 shows the estimation factors used to calculate total capital costs, and Table 4-4 shows the annualized cost factors used to estimate total annualized costs.

Based on the above scale-up of the vendor equipment cost estimate and other cost factors, Table 4-3 shows a total capital investment of approximately \$28.0 million per turbine or about \$83.9 million total for three turbines. This is a huge capital investment on a system that is, to date, unproven on a turbine of this scale. The annualized costs in Table 4-4 assume 10-year financing lifetime at an EPA-recommended pretax marginal rate of return of 7% (EPA 1996).<sup>2</sup> This cost estimate includes a 10% contingency on total capital costs, but no contingencies for other annual costs.

<sup>2</sup> Capital recovery factor (CRF):  $CRF = [i(1+i)^n]/[(1+i)^n - 1]$ , where  $i$  = pretax marginal rate of return and  $n$  = equipment economic lifetime (typical length of financing).

**Dry Low NO<sub>x</sub> and Selective Catalytic Reduction.** The most stringent control technology identified during our review as currently commercially available for F-Class and G-Class turbines is the combination of DLN controls followed by SCR. The cumulative control resulting from DLN and SCR for similar turbines is a NO<sub>x</sub> emission rate estimated to be 2.5 ppmvd (at 15 percent O<sub>2</sub>) on a 3-hour rolling average. This level of emissions control has been proposed by several facilities in order to satisfy stringent LAER standards.

DLN is a combustion system design. Virtually all gas turbine manufacturers are continuing to research and improve upon advanced combustion technologies, since they represent the most cost-effective NO<sub>x</sub> reduction approach for some turbine users. NO<sub>x</sub> control through combustor design is attractive because there is essentially one dominant source of NO<sub>x</sub> formation in natural gas combustion, as opposed to two sources with liquid or solid fuel combustion. The predominant source of NO<sub>x</sub> emissions from natural gas turbines is the thermal NO<sub>x</sub> formation reaction, which is very dependent on combustor design. This reaction converts natural atmospheric nitrogen (N<sub>2</sub>) and O<sub>2</sub> to NO<sub>x</sub> at the high temperatures of combustion. DLN combustion results in NO<sub>x</sub> emission rates of 9-25 ppmvd (at 15 percent O<sub>2</sub>). SCR is a post-combustion gas treatment technique for reductions of NO and NO<sub>2</sub> in the turbine exhaust stream to molecular nitrogen and water. Aqueous or anhydrous ammonia (NH<sub>3</sub>) is typically used as the reducing agent. The basic reactions are:



Typically, a fixed-bed catalytic reactor is used for SCR. The function of the catalyst is to lower the activation energy of the NO<sub>x</sub> decomposition reaction with ammonia. SCR can typically achieve a 90 percent reduction in NO<sub>x</sub> emissions.

As noted in Table 4-1, DLN with SCR has been permitted to achieve NO<sub>x</sub> emissions of 2.0 – 2.5 ppmvd (at 15 percent O<sub>2</sub>) for nominal 170 MW turbines, based on LAER requirements (which are more stringent than BACT). The use of DLN with SCR at a limit of 3.0 ppmvd (at 15 percent O<sub>2</sub>) NO<sub>x</sub> is the lowest BACT limit found in the EPA RBLC database for recent projects.

The purchased equipment cost was scaled-up from an ABB cost estimate for a GT-24 engine submitted in support of a recent permit application to the Michigan Department of Environmental Quality (MDEQ) (Earth Tech 2000). The scale-up factors used for the 501G turbine are shown in Table 4-5 and 4-6 footnotes. Other cost estimate factors were obtained from the MDEQ application support materials (Earth Tech 2000). Table 4-5 shows the estimation factors used to calculate total capital costs, and Table 4-6 shows the annualized cost factors used to estimate total annualized costs.

Based on the above scale-up of the vendor equipment cost estimate and other cost factors, Table 4-5 shows a total capital investment of approximately \$9.5 million per turbine or about \$28.5 million total for three turbines. Costs in Table 4-6 were annualized over a 10-year financing lifetime at an EPA-recommended pretax marginal rate of return of 7% (EPA 1996).

Because SCR has been found to be economically viable and is proposed for use on this project, cost effectiveness analysis is not necessary to determine BACT.

**Water/Steam Injection and SCR.** Water or steam injection followed by SCR is nearly as stringent as the above control technologies. Injection of water or steam into the turbine combustion zone results in cooling of the flame, thereby reducing the formation of thermal NO<sub>x</sub>. Water or steam injection alone can reduce emissions to a level of 25-42 ppmvd. Additional reduction is then achieved with SCR. The cumulative control of water injection and SCR for large turbines yields LAER NO<sub>x</sub> emission rates of 3.5 ppmvd (at 15 percent O<sub>2</sub>).

The key to this technology is the production of sufficient quantities of high purity water, free from dissolved or suspended solids that could damage the turbine. Water for injection must meet rigorous quality standards for various parameters that include silica content and suspended solids levels. Water for steam production must meet even more stringent standards. A malfunction in the water treatment system could cause deposition of minerals inside the turbine, which could result in turbine damage and maintenance problems.

Water injection ratios are generally less than 1.0 pound of water injected per pound of fuel burned. Steam injection ratios are 0.5 to 2.0 pounds of steam per pound of fuel burned. Water injection typically requires lower ratios for an equivalent NO<sub>x</sub> reduction because of the water's lower temperature and latent heat of vaporization. In any event, the use of water or steam injection significantly increases facility water use when compared to a DLN combustion technology. In addition, water or steam injection lowers the overall facility efficiency because of the quench effect of the diluent injected. However, the turbine's output is greater due to the additional mass flow through the turbine from the diluent.

**Dry Low NO<sub>x</sub>.** DLN technology by itself is a proven method to reduce NO<sub>x</sub> emissions to a level of approximately 9-25 ppmvd. Technical issues associated with this technology have been discussed above.

**Water/Steam Injection.** Water or steam injection can reduce NO<sub>x</sub> emissions to a level of approximately 25-42 ppmvd. Technical considerations for this technology have been discussed above.

**NO<sub>x</sub> BACT Summary For Turbines.** Pursuant to a Top-Down BACT assessment, current NO<sub>x</sub> BACT is 3.0 to 4.5 ppmvd (at 15 percent O<sub>2</sub>) based on DLN/SCR technology. Neither XONON<sup>TM</sup> or SCONO<sub>x</sub><sup>TM</sup> are commercially available technologies for large turbines at this time. Commercial terms may become available for SCONO<sub>x</sub><sup>TM</sup> before the project is constructed. Both SCONO<sub>x</sub><sup>TM</sup> and SCR achieve the same guaranteed NO<sub>x</sub> control level of 2.5 ppmvd (at 15 percent O<sub>2</sub>, 3-hour average), but SCONO<sub>x</sub><sup>TM</sup> has a much higher annualized cost of \$26.6 million vs. \$15.5 million for SCR on 3 turbines. Over an amortized 10-year period, this represents a differential cost of approximately \$110 million with no improvement in guaranteed control level. Thus DLN/SCR is the proposed NO<sub>x</sub> control technology. The proposed BACT NO<sub>x</sub> emissions level is below current BACT levels of 3.0 to 4.5 ppmvd (at 15 percent O<sub>2</sub>), and is equivalent to NO<sub>x</sub> LAER in other states such as California. It is the most stringent BACT limit proposed to

## Exhibit 5

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## PRODUCTS

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## SCONox<sup>TM</sup> for NOx, CO and VOC destruction

### There's No Better System.

In 1997, the U.S. EPA declared SCONox<sup>TM</sup> the Lowest Achievable Emission Rate (LAER) for NOx abatement — establishing it as the standard against which future abatement means will be judged.

Goal Line's SCONox process for energy and industrial applications is based upon a unique integration of proven, proprietary and patented catalytic oxidation and absorption technology. SCONox greatly reduces emission fees and offset costs, and thus offers a lower cost and simplified permitting process for new and retrofit applications. SCONox can be designed to provide an equal or lower pressure drop than an SCR system at comparable emission levels.

Whether you're operating at less than 10MW or greater than 300MW, SCONox is your solution to increasingly stringent regulations.

### And No Ammonia, Either

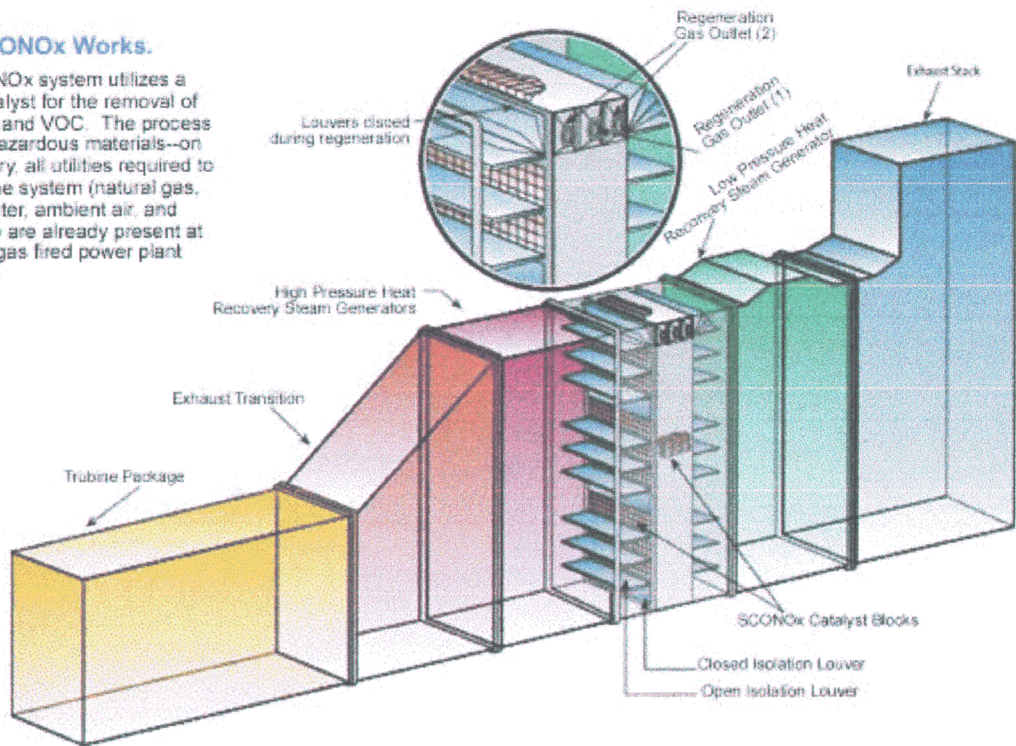
That's right. With SCONox — unlike conventional Selective Catalytic Reduction (SCR) systems — there is no ammonia to be supplied to the system. And no ammonia slip. SCONox reduces NOx, CO, VOC, and formaldehyde emissions as never before, with no production of PM2.5 constituents such as ammonium bisulfate and ammonium nitrate. No ammonia means no risks associated with on-site storage or transport through communities concerned about this hazardous material.

ABB Environmental, Inc. is Goal Line's exclusive SCONox licensee for gas turbine applications greater than 100 MW and a non-exclusive SCONox licensee for less than 100 MW. Goal Line provides catalyst and technical support for all installations.



**How SCONox Works.**

The SCONox system utilizes a single catalyst for the removal of NOx, CO, and VOC. The process uses no hazardous materials--on the contrary, all utilities required to operate the system (natural gas, steam, water, ambient air, and electricity) are already present at a natural gas fired power plant



**The Oxidation/Absorption Cycle**

The SCONox catalyst simultaneously oxidizes NO, CO, and VOCs. NO<sub>2</sub> is absorbed onto the catalyst surface through the use of a potassium carbonate coating. The SCONox catalyst undergoes regeneration periodically to maintain maximum NOx absorption. This oxidation / absorption/regeneration system results in ultra-low emissions.

SCONox subassemblies arrive on-site ready for installation.



**The Regeneration Cycle**

The SCONox catalyst is regenerated by passing a controlled mixture of regeneration gases across its surface in the absence of oxygen. The regeneration gases react with the nitrites and nitrates to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate — the absorber coating that was on the

surface of the catalyst before the oxidation/absorption cycle began. Water (as steam) and elemental nitrogen are exhausted up the stack, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate; the process operates as a true catalyst.

## System Configuration

A large SCONox system arrangement has ten or fifteen sections of catalyst (although this number can vary depending on the size and special design requirements of the individual system). At any given time 80 percent of these rows are in the oxidation/absorption cycle and 20 percent are in the regeneration cycle. Because the same number of rows is always in the regeneration cycle, the production of regeneration gas always proceeds at a constant rate. A regeneration cycle typically lasts for three to four minutes, so each section is in the oxidation/absorption cycle for fifteen to twenty minutes.

The piping system supplies regeneration gas to isolated SCONox sections

This system for operating the louvers during regeneration



SCONox system in place

## How to Get Started

Ideally suited to both new and retrofit applications, the SCONox system can operate effectively at temperatures ranging from 300 to 700°F, does not limit gas turbine performance, and can be installed at the back end of the boiler or in the HRSG within the same envelope reserved for an SCR system. Goal Line will guarantee your emissions using SCONox technology for both new and retrofit installations.

The engineers at Goal Line are ready to go to work for you in designing, sizing, and supplying your SCONox process for power generation or industrial manufacturing. We even provide complete catalyst management services.

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